

2003 Safety-Net Cost Recovery Adjustment Clause Final Proposal

Final Study

Chapter 1 – Overview and Management Direction

SN-03-FS-BPA-01

June 2003



CHAPTER 1: OVERVIEW AND MANAGEMENT DIRECTION

1.1 Purpose

On September 28, 2001, the Federal Energy Regulatory Commission (FERC) granted interim approval to Bonneville Power Administration's (BPA) 2002 WP-02 power rate filing. That rate filing included base power rates and, among other rate features, three separate Cost Recovery Adjustment Clauses (CRAC). The CRACs allowed BPA to keep base rates low and to address financial shortfalls through the variable CRACs, rather than institute higher base rates for the entire rate period. These tools also gave BPA the risk mitigation necessary to have a sufficiently high probability of repaying its obligations to the U.S. Treasury (as measured by Treasury Payment Probability or TPP). The three CRACs are the Load-Based (LB) CRAC, which is designed to cover augmentation costs, the Financial-Based (FB) CRAC, which is designed to help ensure sufficient net revenues, and the Safety-Net (SN) CRAC, which is available if the likelihood of missing a Treasury payment or payment to any other creditor is 50 percent or greater despite the implementation of the LB and FB CRACs.

On February 7, 2003, the BPA Administrator determined that the SN CRAC had triggered, based on a forecast of 50 percent or greater chance of missing a payment to the U.S. Treasury or another creditor during Fiscal Year (FY) 2003. The triggering of the SN CRAC initiates an expedited hearing process to be conducted in accordance with section 7(i) of the Northwest Power Act. The purpose of the SN CRAC is to calculate an adjustment to the rates, set in BPA's 2002 Wholesale Power Rate Case, in order to restore BPA's financial health. As provided in section II.F.3 of BPA's 2002 General Rate Schedule Provisions (GRSPs), the SN CRAC enables BPA to implement an upward adjustment to posted power rates subject to the FB CRAC by modifying the FB CRAC parameters. BPA is proposing changes to the FB CRAC parameters that, to the extent market and other risk factors allow, will achieve a high probability that the

1 remaining Treasury payments during the FY 2002-2006 rate period will be made in full. BPA's
2 proposal includes, consistent with the GRSPs, changes to the Maximum Planned Recovery
3 Amount (the amount of revenues planned to be recovered), the duration (the length of time the
4 SN CRAC can be in place, which can be more than one year), and the timing of collection.
5

6 **1.2 Background**

7 **1.2.1 Safety-Net Cost Recovery Adjustment Clause (SN CRAC).** The SN CRAC triggers
8 based on a forecast of 50 percent or greater chance of missing a payment to the U.S. Treasury or
9 another creditor during the fiscal year. The SN CRAC is used to help BPA recover from
10 financial losses and improve its financial health by increasing the probability that BPA will make
11 its Treasury payment and payments to all other creditors in full through FY 2006. The final
12 proposed SN CRAC rate design formula will adjust rates sufficient to achieve a TPP of 80
13 percent for the remainder of the rate period.
14

15 **1.2.2 Current Financial Situation.** In assessing its financial situation, BPA monitors three
16 important indicators: (1) financial reserves; (2) net revenues; and (3) the credit rating on
17 BPA-backed bonds.
18

19 **1.2.2.1 Financial Reserves.** BPA's financial reserves consist of cash in the Bonneville Fund,
20 including working capital, and any deferred borrowing balance. "Deferred borrowing balance"
21 refers to capital expenditures that will be funded by money borrowed from the U.S. Treasury, but
22 have been temporarily financed with revenues. Estimates of start-of-year reserves in this rate
23 proposal for FY 2004 reflect total BPA reserves. In modeling this final proposal, all reserves are
24 projected as cash in the Bonneville Fund, with no reserves reflecting a deferred borrowing
25 balance.
26

1 Financial reserves are important in two ways. First, financial reserves serve as a buffer for
2 solvency from the cyclical and unanticipated impacts of conducting business in an uncertain
3 environment. BPA, like other hydroelectric utilities, forecasts a range of potential future
4 financial outcomes. High reserve balances can mitigate the financial risk of some of the bad
5 potential outcomes. The higher the reserve balances, the more potentially negative outcomes the
6 reserve balance can mitigate in terms of duration and/or magnitude. During FY 2001, the
7 reserve balance, combined with access to credits against payments to Treasury, helped BPA
8 remain solvent through a particularly difficult period both in terms of duration and magnitude.
9 The second reason reserves are important is that they provide a financial “buffer” which helps
10 maintain BPA’s TPP while minimizing rates.

11
12 **1.2.2.2 Net Revenues.** BPA ended FY 2002 with \$188 million of reserves, \$53 million
13 attributed to the Power Business Line (PBL) and \$135 million attributed to the Transmission
14 Business Line (TBL). *See* SN-03-FS-BPA-01, chapter 7. This amount was a reduction from
15 agency reserves of \$625 million (\$496 million of which was attributed to PBL) at the end of
16 FY 2001. The drop in reserves during FY 2002 was related primarily to PBL’s net revenue loss
17 of \$87 million. Net revenues are defined as revenues minus expenses. When PBL net revenues
18 are adjusted consistent with the FB CRAC methodology, which uses the May 2002 final
19 proposal forecast of Energy Northwest (ENW) debt service and removes FAS 133 adjustments,
20 this -\$87 million becomes -\$390 million. In FY 2003, until the time of BPA’s initial proposal,
21 PBL’s net revenues remained negative and continued to adversely impact agency reserves.

22
23 On June 29, 2001, BPA filed a supplemental proposal to its May 2000 Power Rate Proposal with
24 FERC. The rates BPA proposed in that filing received interim approval on September 28, 2001.
25 In the supplemental proposal, BPA predicted higher PBL net revenues than in BPA’s May 2000
26 final proposal. The two primary factors which drove the expected relative increase in revenues

1 were secondary sales and fish credits. BPA's secondary sales are a function of both market
2 prices and available hydro. Secondary sales were forecasted to provide higher revenues due to
3 BPA's expectation of continued high market prices. At the time, the West Coast was
4 experiencing very high electrical demand relative to supply. The development of new resources,
5 which BPA expected would help bring market prices down eventually, was anticipated to take up
6 to two years. BPA, as well as other utilities on the West Coast, believed the high market prices
7 would continue until those new resources came on line. Lower-than-forecasted revenues for
8 BPA in FY 2002 resulted from an unanticipated and rapid decline in market prices. A number of
9 factors contributed to this decline, including lower demand as a result of a downturn in the
10 economy.

11
12 Another variable in secondary sales revenues is the amount of water in the hydro system
13 available to generate hydroelectricity in any given year. In BPA's supplemental proposal, BPA
14 expected average hydro production for all years of the rate period. However, actual hydro
15 production in FY 2002 was lower than expected. Although the hydro conditions appeared to be
16 about normal over the January-July 2002 period, the FCRPS stored a significant amount of water
17 to partially replenish the low reservoirs resulting from the 2001 drought. This storage resulted in
18 less 2002 hydro production than forecasted in BPA's supplemental proposal. The net result of
19 these two factors (lower than expected prices and less than expected hydro production) was that
20 BPA sold less energy, and at lower prices, than forecasted in BPA's supplemental proposal.

21
22 In addition to expecting revenue from secondary sales, the second source of the expected relative
23 increase in revenues in BPA's supplemental proposal consists of credits toward BPA's Treasury
24 payments based on fish-related costs and impacts on operations (fish credits). These fish credits
25 were expected to contribute significantly to BPA's total revenues, in part due to expected high
26 market prices. Fish credits contribute to BPA's overall revenues through a credit against BPA's

1 payment to the U.S. Treasury. However, these credits now are expected to be substantially lower
2 over the rate period than previously forecasted. The reasons for the reduction include a
3 reallocation of project purposes at Grand Coulee, lower wholesale power prices, and reduced
4 availability of Fish Cost Contingency Fund (FCCF) credits that were all but exhausted at the end
5 of 2001 because of the severe drought.

6
7 In addition to lower-than-forecasted revenue credits, PBL cost increases of approximately
8 \$1.5 billion in total over the rate period contributed to BPA's eroding financial condition (not
9 including offsetting increases in revenue due to the increase in expenses, and the risk to certain
10 expense categories embedded in the Non-Operating Risk Model (NORM) assessment). These
11 increases included PBL Internal Operations, Corporate Overhead, Residential Exchange
12 Settlement Agreements, Power Generation, Renewable Projects, Transmission Acquisition, Civil
13 Service Retirement Payments, Terminated Projects, Fish and Wildlife, Conservation and
14 Renewable Discount, Other Public Benefits, Non-Federal Debt Service, Depreciation,
15 Amortization, and Net Interest (not included are Power Purchases and Augmentation).
16 Associated with these expense items are approximately \$500 million of offsetting revenues in
17 total over the rate period, such as increased generation from the hydro system and Columbia
18 Generating Station, and approximately \$120 million for non-operating risks. Because of the
19 energy crisis in 2001, BPA is still owed about \$90 million by the California Independent System
20 Operator and Power Exchange. Of this amount, BPA made an accounting adjustment to PBL net
21 revenues in 2002 of about \$24 million to reflect the risk that BPA may never be paid this
22 amount. Additionally, BPA has take-or-pay contracts that obligate the direct service industrial
23 customers (DSIs) to pay take-or-pay damages on IP power when such power is not purchased
24 (curtailed) and BPA must sell the curtailed amount in the surplus market when the market value
25 is less than the IP value. The DSIs are obligated to pay BPA the difference under those
26 circumstances so that BPA is made whole. BPA is at risk of not being paid about \$30 million of

1 FY 2002 take-or-pay damages due to DSI bankruptcies or other financial difficulties. The
2 portion of money at risk is \$54 million, which is reflected as a Bad Debt Expense in BPA's
3 income statement. Aside from the significantly decreased revenues PBL experienced during the
4 first two years of this rate period, PBL forecasts significant losses for the remainder of the rate
5 period. At the time of BPA's SN CRAC initial proposal, these losses were expected to be
6 \$339 million for FY 2003-2006 even with maximum contributions from the FB CRAC in each
7 year. These losses are referred to as a "net revenue gap." Since that time, BPA's financial
8 situation has improved. These improvements are due to aggressive cost cutting resulting in over
9 \$80 million in net expense reductions, more favorable water conditions, higher forecasted market
10 prices, and cash benefits from debt optimization, among other things. BPA continues to pursue
11 additional cost reductions for the remainder of the rate period. In this final study, the net revenue
12 gap for FY 2003-2006 without an SN CRAC is now forecast to be about \$212 million.

13
14 **1.2.2.3 Credit Rating.** The credit ratings for BPA-backed bonds were downgraded this spring
15 by Fitch Ratings to AA- as well as placed on "negative outlook" by Standard and Poor's
16 (AA-rating), even in view of the expectation that BPA will proceed with the SN CRAC process
17 and reinforce its TPP and liquidity positions. These downgrades may also affect future
18 refinancing of ENW and other BPA-backed bonds. The Standard and Poor's report states that a
19 downgrade could be prompted by "the use of any debt restructuring savings to offset current
20 operating expenses...", "failure to implement an adequate SN CRAC...", or "any restructuring
21 of federal Treasury obligations." See Attachment 1 at the end of this chapter.

22 23 **1.3 BPA's Response**

24 Faced with a deterioration of its overall financial condition, BPA sent a letter to its customers,
25 including power rate case parties, and other interested entities in the region on July 2, 2002. The
26 letter announced the beginning of a public comment process on BPA's financial condition,

1 referred to as “Financial Choices.” The Financial Choices process examined a variety of
2 financial and program options for addressing PBL’s FY 2003-2006 financial challenges. In this
3 process, BPA described those financial challenges, the actions BPA had already taken to address
4 the problem, and the financial outlook for the remainder of the rate period. Additionally, BPA
5 identified a variety of potential financial alternatives that, separately or in combination, could
6 form the basis of a solution to PBL’s financial condition.

7
8 BPA received significant public comment during the Financial Choices process. As a result of
9 the process, BPA made decisions to reduce, eliminate, or defer certain expenses. BPA issued a
10 Financial Choices close-out letter to the region on November 22, 2002, outlining BPA’s plan, in
11 part, for meeting PBL’s financial challenges. The actions BPA has taken, and will take, include
12 the identification of \$350 million in expense savings, expense deferrals, and other actions for the
13 FY 2003-2006 period. These actions are reflected in this final proposal. *See* Lefler, *et al.*,
14 SN-03-E-BPA-06; SN-03 Study, SN-03-E-BPA-01, chapter 3; and Keep, *et al.*,
15 SN-03-E-BPA-11. As part of this effort, BPA has requested, and ENW has implemented, a
16 program to purchase surety bonds to release bond reserve funds to pay for some near-term debt
17 service costs at ENW. Also, ENW negotiated a \$23 million settlement with the Bank of America
18 for the Bank’s role as paying agent on certain BPA-backed bearer bonds. ENW plans to provide
19 \$22 million of the settlement proceeds to BPA. In addition, BPA and Enron reached a settlement
20 on power purchase augmentation agreements BPA has with Enron. Under the settlement, BPA
21 agreed to terminate a series of contracts with Enron, and those savings are reflected in BPA’s
22 final study.

23
24 BPA realizes that the practice of assuming significant cost cuts without a complete plan on how
25 to achieve them has contributed to BPA’s current financial condition. BPA has been given
26 assurances by ENW, the U.S. Army Corps of Engineers (Corps), and the U.S. Bureau of

1 Reclamation (Reclamation) that each will rigorously manage its expense levels to the limits
2 established in this final proposal.

3
4 The cost reductions associated with BPA's internal operating expenses charged to power rates in
5 the Financial Choices process were largely reflected in the initial proposal. Cost cutting
6 reflected in this final study includes a total of \$36.2 million in additional reductions in PBL
7 Internal Operations, Corporate G&A, and Shared Services expenses, including approximately
8 \$20 million of cost reductions that were inadvertently omitted in the initial proposal.

9
10 Another area of identified cost reduction is the discussions between the public agency customers
11 and the IOUs to reach a settlement of the IOU Residential Exchange Program settlement
12 contracts agreements. Chapter 7 of this study describes the contingent feature of the SN CRAC
13 rate design, which will allow BPA to reflect any cost reductions in BPA's rates if that settlement
14 is reached.

15
16 **1.3.1 Summary of Proposal.** BPA is proposing a three-year variable SN CRAC adjustment to
17 power rates, which has a cap limiting the amount of revenues that can be collected each year.
18 The SN CRAC also includes a contingent adjustment and spending limits on certain budget items
19 that will not automatically be collected in the annual SN CRAC calculation. The proposed
20 SN CRAC design is somewhat similar to the existing FB CRAC as described in BPA's 2002
21 GRSPs and is in addition to the FB CRAC. The proposed SN CRAC is a temporary upward
22 adjustment to posted power rates based on the level of end-of-year Accumulated Net Revenue
23 (ANR) for PBL, as defined in the FB CRAC section in the 2002 GRSPs. The August forecast of
24 ANR for each fiscal year from 2003-2005 is compared to the SN CRAC threshold applicable to
25 that fiscal year. If the forecasted ANR is below the threshold, an SN CRAC rate adjustment will
26 be implemented to collect either the amount of the difference between the forecasted ANR and

1 the threshold, or an annual cap, whichever is smaller. The proposed SN CRAC rate adjustment
2 will be determined annually, go into effect October 1 of each year, and be in effect for the
3 remainder of that fiscal year. The adjustment will be applied to the appropriate rates for the
4 12-month fiscal year. The SN CRAC rate adjustment contains a provision to rebate to customers
5 previously collected money if PBL ANR exceeds threshold levels by \$15 million. The SN
6 CRAC design also includes spending limits on certain cost categories. The expected value of the
7 SN CRAC is 15 percent in 2004, 17 percent in 2005, 15.7 percent in 2006, or 15.9 percent on
8 average over the three years. This reflects an expected value increase in overall rates from FY
9 2003 of about 5 percent. *See* chapter 7 for a more detailed discussion of the SN CRAC design.
10

11 **1.3.2 Criteria.** For the SN CRAC proceeding, three criteria were used to develop the SN
12 CRAC mechanism. First, section 7(a)(1) of the Northwest Power Act states, in part, that BPA
13 shall establish rates that recover, in accordance with sound business principles, the costs
14 associated with the acquisition, conservation, and transmission of electric power, and other cost
15 expenses incurred by the Administrator. Therefore, BPA will set rates sufficient to cover costs.
16 Second, BPA is concerned about the impact of any rate increase on the economy of the Pacific
17 Northwest, and so, to the extent possible, the rate design should mitigate the level of any rate
18 increase. Third, because the FB and SN CRACs apply to somewhat different customers and
19 involve different contractual provisions, and in order to simplify billing and accounting, the FB
20 CRAC will be left largely unchanged and a separate SN CRAC will be created. The FB CRAC
21 thresholds will be adjusted to be the same as the SN CRAC thresholds so that the two CRACs
22 are better coordinated. Chapter 7 of this study discusses each of these criteria and elaborates on
23 how these criteria are met with the proposed SN CRAC mechanism.
24
25
26

1.4 Organization of Study

This study contains several chapters, which together support BPA's SN CRAC proposal. Chapter 2 describes the methodology for PBL's loads and sales forecasts. It also includes assumptions used in the development of the hydro regulation study and other resource forecasts. Chapter 3 contains BPA's generation revenue recovery study, including a forecast of generation expenses. Chapter 4 describes the methodology and resulting forecast of PBL's secondary revenues. Chapter 5 contains PBL's revenue forecast at current and proposed rates. Chapter 6 describes the analysis that quantifies PBL's net revenue risk. Chapter 7 describes the ToolKit model, the proposed SN CRAC design, and the associated GRSPs.

Bonneville Power Administration

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Rationale

The outlook on the 'AA-' rating on Energy Northwest's debt, secured by payments from the Bonneville Power Administration, is revised to negative and the rating is affirmed. The outlook revision reflects the increasing likelihood that Bonneville and its customers will decide to use cash savings provided by the debt optimization program, specifically the \$315 million cash savings in fiscal year 2003 that is planned to be used for the prepayment of Treasury debt, to finance current operating expenses instead of using the money to pay down more expensive Treasury debt, as originally intended when the debt optimization plan was constructed. Financial pressures on Bonneville resulting from weak hydrology conditions and the high cost of replacement power have culminated in the deterioration of cash reserves to \$188 million at the end of fiscal 2002 from \$811 million at the end of fiscal 2000. Now that cash reserves have been depleted, ongoing cost pressures are prompting calls from Bonneville's customers to use debt optimization savings to offset the need for additional rate increases rather than to prepay Treasury debt, which would essentially hold the overall debt levels of Bonneville at a stable level. The decision to extend debt instead of using rate increases to cover costs through fiscals 2003-2006 is not reflective of a 'AA' category credit even with the structural advantages afforded to the Energy Northwest bonds by the net billing agreements, which allows for payment of the debt service before any and all operating expenses or other debt obligations of Bonneville.

The preservation of the 'AA-' rating will depend on successful implementation of the Safety-Net Cost Recovery Adjustment Clause (SN CRAC) in the summer of 2003, which is expected to provide additional revenues through a 16% rate increase. This rate increase, in conjunction with approximately \$300 million of identified cost reductions and deferrals through fiscal 2006 and the use of cash tools such as the \$250 million line of credit, should allow Bonneville to end fiscal 2003 with between \$100 million and \$200 million in cash reserves. In addition, Bonneville has revised its projections of revenues from wholesale power sales down by \$650 million during fiscals 2003-2006, as it had been optimistic due to high projected wholesale prices that were above actual prices being achieved in the market. Although Bonneville's liquidity will remain seriously constrained in fiscal 2003 even with the achieved cost cuts, Bonneville is exploring the optional use of a \$250 million federal line of credit to manage its immediate cash flow needs.

The 'AA-' rating on the Energy Northwest debt reflects the following credit strengths:

- Legal payment of the \$5.9 billion in Energy Northwest (formerly the Washington Public Power Supply System) obligations as an operating expense of Bonneville

Standard & Poor's Document: March 13, 2003

- through the net billing agreements, which are senior to approximately \$7 billion in outstanding Treasury debt and federal obligations. This offers bondholders the assurance of over 2.0x coverage as long as sufficient revenues are collected to meet all of Bonneville's debt obligations, including the Treasury debt;
- Structural advantages offered by the net billing agreements provide that, beginning on July 1 of each year, cash to pay each Bonneville wholesale power bill is sent directly from approximately 100 Energy Northwest participants (all Bonneville customers) to Energy Northwest to pay operating expenses and debt service on the Energy Northwest debt. Only once the Energy Northwest obligations are met do participants begin sending payments to Bonneville to fund Bonneville's operating and remaining debt obligations.
 - The presence of rate setting authority in Bonneville's existing contracts, including three separate Cost Recovery Adjustment Clauses (CRACs), and political support to use those CRAC mechanisms that should allow Bonneville to maintain strong debt service coverage on the Energy Northwest debt as well as meet its scheduled Treasury repayments;
 - Generation rates remain reasonable and competitive at approximately 3.0-3.4 cents per kilowatt-hour (kWh) as of April 1, 2003, despite low hydrology and the high cost of replacement power. The anticipated SN CRAC increase will raise rates to between 3.2-3.6 cents/kWh as of Oct. 1, 2003;
 - Successful implementation of the "Slice" product that allocates 22% of the federal system to purchasers who are obligated to pay a percentage of the system costs in return for a percentage of system output, reducing Bonneville's exposure to low water flow, although Bonneville retains full operational authority over the system. This benefit is mitigated by the increased operating and financial risk that it places on Bonneville's customers who select this product;
 - Limited exposure to low water levels, currently around 70% of normal, in the 2003 water year because of Bonneville's current long position resulting from the economic recession in the region and the shutdown of approximately 1,500 MW of industrial load at the aluminum smelters. Lower water is resulting in higher market energy prices in the Northwest, which is increasing the amount of revenues Bonneville receives from wholesale sales.

Rating concerns that could prompt a downgrade include:

- The use of any debt restructuring savings to offset current operating expenses, which would constitute a deferral of the cost recovery needed into future years;
- Failure to implement an adequate SN CRAC, which is needed at 16% absent any additional cost cuts, to keep cash reserves at a minimum operating level; or
- Any "restructuring" of federal Treasury obligations, although Bonneville does have the legal flexibility to "restructure" its federal obligations at any time with minimal financial penalties.

Although Standard & Poor's Ratings Services realizes that Bonneville is under intense financial pressure and that deferring some costs into years beyond 2006, when the "augmentation costs" and the responsibility to serve approximately 1,500 MW of Direct Service Industrial (DSI) load go away, is an attractive option to customers, the use of these short-term solutions are not reflective of a 'AA' credit.

Standard & Poor's Document: March 13, 2003

Liquidity.

As mentioned above, Bonneville's liquidity of only \$188 million at the end of fiscal 2002 remains seriously constrained, and it has limited liquidity tools available--primarily the \$250 million federal line of credit that is not intended to be used for ongoing operations and the anticipated \$315 million in cash savings that is expected to be produced by this \$1.2 billion debt restructuring. Although the use of the \$315 million in 2003 provides some liquidity flexibility, its use would be at the cost of extending existing debt obligations and would be viewed as a negative credit factor. Offsetting liquidity concerns is the real ability of Bonneville to reschedule payments related to its federal obligations, which account for over half of Bonneville's \$13 billion in total outstanding debt obligations.

Outlook

The negative outlook reflects concern that the stringent effects of prior rate increases coupled with ongoing revenue shortfalls have prompted Bonneville and its customers to consider solutions to its financial challenges that will avoid rate increases. The solutions under consideration, however, are not supportive of credit quality at the current rating level. Bonneville has announced its intent to trigger the SN CRAC and is proceeding with a rate case that will require final FERC approval. Ongoing revenue shortfalls from wholesale revenues, despite higher prices due to low water conditions, have prompted a discussion of reducing the probability of Treasury repayment, which was previously considered unthinkable by both Bonneville and its customers. Although no party is encouraging missing a payment to Treasury, Bonneville's decimated cash reserves, limited liquidity options, and the time lag between the implementation of the SN CRAC and the collection of the additional revenues make the non-payment of Treasury a real possibility in the next two years. The use of debt restructuring savings for current operations or any delay in the repayment of scheduled Treasury payments would prompt a rating downgrade, even though bondholders have a priority lien on revenues through the net billing agreements.

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Fitch Lowers Energy Northwest's Electric Revs To 'AA-'; Rating Outlook Stable [Ratings](#)

12 Mar 2003 11:36 AM

Fitch Ratings-New York-March 12, 2003: Fitch Ratings has lowered the rating on Energy Northwest's \$5.8 billion outstanding prior lien and electric revenue bonds to 'AA-' from 'AA', and assigned a 'AA-' rating to a proposed \$714 million series 2003A (tax-exempt) and B (taxable) refunding electric revenue bonds. The Rating Outlook is Stable for the Energy Northwest bonds, which had previously been on Rating Watch Negative (Sept. 9, 2002). The fixed-rate 2003A and B bonds will refund certain Project No. 1, Project No. 3 and Columbia Generation Station prior lien and electric revenue bonds. The bonds are scheduled to price on Mar. 18, 2003, with Salomon Smith Barney as lead underwriter.

The rating downgrade reflects the less than consistent and weakened financial performance of the Bonneville Power Administration (BPA), which is contractually obligated to pay debt service on the Energy Northwest bonds. Below normal water conditions, a decline in prices received for surplus hydroelectric energy and a softness in the regional economy have negatively impacted on BPA's creditworthiness. While there remains uncertainty regarding the level of BPA's financial performance, planned cost savings and rate adjustments should be beneficial.

Factors that support the rating include BPA's obligation to pay debt service on the Energy Northwest bonds prior to its U.S. Treasury payments, providing good debt service coverage protection for Energy Northwest, the importance of the federal power marketing agency in supplying electricity and transmission service in the Pacific Northwest and recently implemented rate adjustments. The recent implementation of the three-step, cost adjustment program, adds improved rate flexibility and reduces BPA's need to maintain larger reserve positions. Wholesale rates are forecasted to remain competitive for the region, but will be above historical levels. Finally, BPA's (the agency) increasing reliance on financial tools to bolster near term performance has the potential to further weaken the agency's long-term credit standing.

Energy Northwest owns and operates the Columbia Generating Station, previously known as Nuclear Project No. 2. BPA purchases the project power under agreement and markets the power along with electricity from 30 federally-owned hydroelectric projects across its high-voltage transmission network throughout the Pacific Northwest. BPA is the largest of the regional federal power marketing agencies.

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